

**MULTI-POLLUTANT EMISSIONS CONTROL:
PILOT PLANT STUDY OF TECHNOLOGIES FOR REDUCING
Hg, SO₃, NO_x AND CO₂ EMISSIONS**

**Semi-Annual Technical Progress Report No. 6
For The Period March 5, 2004 through September 4, 2004**

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ABSTRACT

This is the sixth semi-annual Technical Progress Report for the subject agreement. During this period, sampling for Parametric Testing (Task 5) and Humidification Tests (Task 6) were completed. Long Term Testing (Task 7) and the Corrosion Study (Task 8) were started. Data analysis and reporting for Baseline Testing (Task 3), Sorbent Evaluation (Task 4), Parametric Testing (Task 5) and Humidification Tests (Task 6) were completed. Maintenance (Task 2) of the pilot plant ESP and other equipment has continued. These aspects of the project, as well as progress on public outreach and contract administration issues, are discussed in detail in this report.

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INTRODUCTION

Coal-fired electric generating plants are the largest remaining unregulated source of anthropogenic mercury (Hg) emissions in the U.S. The U.S. Environmental Protection Agency expects to issue a final regulation by April 2005 to reduce these emissions.

Although no technology currently available eliminates mercury emissions uniformly across the spectrum of power plant configurations, some technologies can reduce mercury emissions from power plants. For example, flue gas desulfurization systems can reduce stack mercury emissions by 50% to 70%. Activated carbon injection may be considered to be the leading technology currently available for maximum removal of mercury; it has been demonstrated at full-scale for short times, but it is very expensive to use.

CONSOL Energy Inc., Research & Development (CONSOL) and Allegheny Energy Supply (AES), with support from the U.S. Department of Energy's National Energy Technology Laboratory, are conducting a three-year program to construct and operate a 1.7 MWe equivalent pilot plant using flue gas from a coal-fired power generating station to develop innovative technology for reducing mercury emissions from coal-fired power plants. Other participants are ALSTOM Power Inc., Environmental Elements Corp., and Carmeuse Lime, Inc. The technology works by cooling the exhaust gases and permitting the mercury to absorb on the coal fly ash. The fly ash and mercury are then captured in the power plant's existing particulate collection device. An alkaline material is injected to prevent corrosion of the power plant's air heater and ductwork. In addition to controlling mercury emissions, the technology will reduce the emissions of sulfur trioxide and ameliorate the visible plume problem sometimes associated with selective catalytic reduction applications. The technology can also allow improved generating efficiency, which would lead to lower emissions of most pollutants and carbon dioxide.

The facility was built at AES's Mitchell Station in Courtney, PA, and the technology will be tested on a 16,500 lb/h (3640 scfm) slipstream of the flue gases from the 288-megawatt, coal-fired Unit No. 3. The test program includes a series of long-term tests to evaluate the impact of the technology on the performance of specific power station components and mercury stability tests on the collected fly ash.

EXECUTIVE SUMMARY

This is the sixth semi-annual Technical Progress Report for this project. Sampling for Parametric Testing (Task 5) and Humidification Tests (Task 6) were completed. Long Term Testing (Task 7) and the Corrosion Study (Task 8) were started. Data analysis and reporting for Baseline Testing (Task 3), Sorbent Evaluation (Task 4), Parametric Testing (Task 5) and Humidification Tests (Task 6) are presented. Considerable maintenance work was done on the pilot electrostatic precipitator (ESP) and slurry injection nozzle in preparation for Long Term Testing (Task 7). These aspects of the project, as well as progress on public outreach and contract administration issues, are discussed in detail in this report

EXPERIMENTAL

A diagram of the pilot plant is shown in Figure 1. Please refer to this diagram for sampling locations referred to in the following text.

RESULTS

Plant Construction (Task 1)

Completed.

Start-up and Maintenance (Task 2)

Start-up was completed. A majority of the on-going maintenance has involved the pilot ESP and slurry injection nozzle.

Baseline Testing (Task 3)

Baseline testing was started on August 28, 2003 and completed on January 29, 2004.

Upon completion of the Baseline Testing and preceding the start of $\text{Mg}(\text{OH})_2$ injection (Task 4), one cold-end basket and one hot-end basket were removed from the air heater for inspection and replaced with two new baskets. ALSTOM's examination of the baskets to assess the condition of the metal surfaces revealed no sign of corrosion, or ash buildup or any other deposits on the metal surfaces.

Sorbent Testing (Task 4)

Sorbent Evaluation testing was started on February 24, 2004 and completed on March 3, 2004.

The pilot air heater showed no signs of fouling during the four operating periods of 6 to 7 hours per day of reagent injection and low temperature operation.

Parametric Testing (Task 5)

Parametric testing was started on March 24 and completed on March 25, 2004. The following tests and maintenance operations were performed:

- On March 24 and 25, the flue gas operating temperature at the air heater outlet was reduced to 225 °F while $\text{Mg}(\text{OH})_2$ reagent was injected at a rate of approximately 4:1 molar $\text{Mg}:\text{SO}_3$ to determine the impact on mercury capture. Mercury and flyash sampling were conducted at the pilot electrostatic precipitator (ESP) gas inlet (location F), gas outlet (location G) and flyash discharge on March 24 and 25. In spite of the fact that the second field of the pilot ESP was shutdown due to failure of the controller and the first field failed due to a high voltage insulator failure on March 25, the flyash removal remained at 99 and 90 percent during the testing. The pilot air heater showed no signs of increased pressure drop due to fouling during the two days (6-7 hours each) of operation at these conditions. This completes the testing aspect of Task 5. The Task 5 Ontario-Hydro sampling train data are shown in Table 1. The Task 5 analyses of $\text{Mg}(\text{OH})_2$ slurry samples are shown in Table 2. The Task 5 analyses of coal and flyash samples are shown in Table 3.
- On March 26, a representative from Environmental Elements Corp. (EEC) inspected the controller and other problems at the pilot ESP. Several components in the high-voltage and current-control systems were replaced. The high-voltage cable termination at the transformer was repaired and a failed insulator rod was replaced on the first field. The insulator rod failure was due to acid condensation which occurred during a brief period when the pilot plant operated without $\text{Mg}(\text{OH})_2$ injection. After these repairs were made, it became apparent that the wall bushing on field #2 had failed. The controller parameters were adjusted to improve the ESP operation.

Humidification Tests (Task 6)

Humidification tests to determine the impact of water-spray cooling on mercury capture were started on April 1 and completed on April 13, 2004. The following tests and maintenance operations were performed:

- On April 1, $\text{Mg}(\text{OH})_2$ reagent was injected at a rate of approximately 4:1 molar $\text{Mg}:\text{SO}_3$ and the pilot air heater was operated to control its flue gas exit temperature at 312 °F. The water spray system was operated to reduce the flue gas temperature at the ESP inlet to 240 °F. Mercury and flyash sampling were conducted at the pilot ESP gas inlet (location F), gas outlet (location G) and flyash discharge on April 1. The first and third fields (but not the second field) of the pilot ESP were operating during this test. Further testing was delayed due to water condensation in the flyash sampling equipment at the pilot ESP.
- On April 13, Humidification testing was completed at essentially the same conditions as used on April 1. Two sets of mercury and flyash samples were taken at the pilot electrostatic precipitator (ESP) gas inlet (location F), gas outlet (location G) and flyash discharge on April 13 to determine the impact of water-spray cooling on mercury capture. Task 6 Ontario Hydro sampling train data are shown in Table 4. The Task 6 analyses of $\text{Mg}(\text{OH})_2$ slurry samples are shown in Table 2. The Task 6 analyses of coal and flyash samples are shown in Table 3.

Long-term Testing (Task 7)

Preparations for long term testing were started on April 16 and actual long-term testing began on August 21, 2004. The following maintenance operations were performed:

- In July, The replacement high-voltage cable for Field #2 of the pilot ESP and the air-barrier nozzles for the $\text{Mg}(\text{OH})_2$ reagent injection and water spray lances were delivered and installed.
- From July 23 to 29, Environmental Elements sent a technician to address high-voltage breakdown at the transformer bushing on pilot ESP Field #1, and low voltage and current conditions on Field #2 of the pilot ESP. The high-voltage breakdown at the transformer bushing on Field #1 was resolved, but the low voltage and current conditions on Field #2 were due to a transformer failure that could not be repaired readily. Thus, moving forward, the ESP will be operated with Field #2 turned off or at 27 kV (instead of at the 45-55 kV expected for a well-operating field). This will be satisfactory because most of the short-term testing was completed with Field #2 turned off (Tasks 5 and 6), or at low voltage (Tasks 3 and 4) and yet the pilot ESP collected virtually all of the particulate mercury from the gas, as indicated by Ontario Hydro speciation results.
- During the week of August 9, one each of a cold-end and a hot-end basket from the pilot air heater were removed for inspection by Alstom. Replacement baskets were installed.
- During the week of August 16, the PLC programming modifications to improve pilot plant operability were completed and tested. The calibrations of the temperature and pressure transmitters were checked to verify proper operation.
- On August 21, long-term testing began. The gas was cooled via the pilot air heater to 220 °F at the pilot ESP inlet. Magnesium hydroxide was injected at a molar ratio of approximately 4:1 with the anticipated sulfur trioxide. The magnesium hydroxide injection slurry nozzles plugged after only eight hours of operation. Lechler, the nozzle supplier, indicated that similar problems have occurred in another application, and they agreed to send us a redesigned nozzle. So that testing could continue to operate the pilot plant until the new nozzle arrives, we chamfered the holes in the existing nozzle, per Lechler's recommendations. This modification allowed up to 30 hours of operation before cleaning was required. Long-term testing was re-started on August 27. From August 27, 2004, through September 3, 2004, two 30-hour runs were completed.

Corrosion Study (Task 8)

The Corrosion Study is underway. A temperature-controlled coupon at the pilot ESP inlet (location F) and in-duct coupons at the pilot ESP outlet (location G) are being exposed.

Public Outreach (Task 14)

A presentation covering results from all the short-term tests (Tasks 3 – 6) was delivered at the DOE Mercury Control Technology R&D Program Review Meeting in Pittsburgh on July 14 and 15, 2004. The presentation slides appear as Attachment A. A revised presentation was made at the Power Plant Air Pollution Control “Mega” Symposium, which was held August 30 through September 2, 2004 in Washington, DC. The presentation slides appear as Attachment B. The written paper appears as Attachment C.

Program Management and Contract Administration (Task 16)

In June 2004, the contract was amended to revise the statement of work, increase the value of the contract, and effect other changes.

DISCUSSION

The principal results and implications of Tasks 3, 4, 5, and 6 are discussed in detail in Attachments A, B, and C. Several additional topics are discussed below.

Impact of Magnesium Hydroxide Injection on Flyash Composition

Table 5 shows the analyses of three pilot ESP flyash samples collected during the baseline period, and during testing periods with two different levels of magnesium hydroxide injection and two different ESP inlet temperatures. The impact of magnesium hydroxide injection on the ash composition is apparent: as the magnesium to sulfur trioxide injection ratio increases from 0 to 1.9 to 3.7, the MgO concentration in the flyash increases from 0.76 to 1.1 to 1.6%.

Analysis of Magnesium Hydroxide

Table 5 also shows the analyses of the by-product magnesium hydroxide being injected during those periods. The magnesium hydroxide has mercury content of about 0.9 mg/kg on a dry basis; this concentration is higher than that of the feed coal and even higher than that of the flyash (presumably because it is a by-product of a wet FGD process). However, the magnesium hydroxide injection rates are such that, even at the high injection ratio of 4/1, the mercury flux from the injected magnesium hydroxide is only about 3% of that from the incoming flue gas. This small contribution has been ignored.

Potential Source of Bias in SO₃ Sampling Not a Concern

A concern was raised that our reported sulfur trioxide concentrations might be biased low during the periods of magnesium hydroxide injection, because the probe filter could build up a cake of solids, which could then react with the sulfur trioxide before it enters the inner probe. For sulfur trioxide sampling, we use the controlled condensation method reported in detail in reference. For the testing under this project, the probe was positioned to extract the gas at 90 degrees from its flow direction. Table 6 shows sulfur trioxide concentrations at various locations around the pilot air heater, measured in duplicate trials, at two different magnesium injection ratios. Table 6 shows data for the gas phase (i.e., passing through the filter) sulfur trioxide, and for the sulfur trioxide

retained in the filter. The data are expressed as ppmv of the volume of gas sampled, but corrected for air to 0% oxygen. In all cases, the filter values are "less than or equal to," because they were at or below detection limits, and in all cases this value is very small compared to the corresponding gas-phase value. Thus, we conclude that the potential error described above does not appreciably affect our reported values.

CONCLUSION

Parametric Testing (Task 5) and Humidification Tests (Task 6) were completed. Long Term Testing (Task 7) and the Corrosion Tests (Task 8) were started. Data analysis and reporting for Baseline Testing (Task 3), Sorbent Evaluation (Task 4), Parametric Testing (Task 5) and Humidification Tests (Task 6) were completed. The working schedule for the entire project is shown in Figure 3.

The following principal conclusions can be drawn at this stage of the test program:

- $\text{Mg}(\text{OH})_2$ slurry injection between the economizer and air heater is effective for removal of sulfur trioxide.
- Mercury removal with the ESP is improved with decreased ESP inlet temperature and may be improved at the lower temperatures with higher unburned carbon content in the flyash.
- Approximately 50% ESP mercury removal was demonstrated with cooling via air heater or water spray. At baseline conditions, mercury removal was about 25%.
- Emissions of elemental mercury were about the same at low-temperature conditions and at baseline conditions. Thus, the additional mercury removed at lower temperatures is mostly oxidized mercury.
- The Ontario-Hydro mercury speciation method appears to suffer problems with high-dust streams at temperatures of less than or equal to 250 °F.

REFERENCES

1. DeVito, M. S.; Smith, D. L. "Controlled Condensation Method: New Option for SO_3 Sampling"; *Power* magazine; February 1991.

Table 1. Hg Sampling – Ontario Hydro Sampling Train Data
TASK 5 – Parametric Testing

Location	F	G	F	G	F	G	F	G
Date	3/24/04	3/24/04	3/25/04	3/25/04	3/25/04	3/25/04	Avg	Avg
Start Time	13:10	13:10	10:32	10:32	14:29	14:30		
Stop Time	15:25	15:18	12:45	12:41	17:10	16:43		
Test Number	F-5-1	G-5-1	F-5-2	G-5-2	F-5-3	G-5-3		
Sample Type	OH-Hg	OH-Hg	OH-Hg	OH-Hg	OH-Hg	OH-Hg		
Y factor of dry gas meter -	1.038	0.984	1.038	0.984	1.038	0.984	1.038	0.984
Gas Volume - ft ³	45.93	80.69	45.78	82.33	44.89	81.48	45.53	81.50
Delta H of dry gas meter - " H ₂ O	0.53	1.98	0.53	1.98	0.53	1.98	0.53	1.98
Meter Temperature - °F	72.0	64.3	76.0	72.1	89.6	81.8	79.2	72.7
C Factor of pitot tube -	0.827	0.796	0.827	0.796	0.827	0.796	0.827	0.796
Nozzle Diameter - inches	0.212	0.276	0.212	0.276	0.212	0.276	0.212	0.276
A n (area of nozzle) - ft ²	0.00025	0.00042	0.00025	0.00042	0.00025	0.00042	0.00025	0.00042
Area of Stack (Single of Du) - ft ²	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
H ₂ O Weight - gm	84.3	120.3	90.3	128.8	93.0	138.4	89.2	129.2
Sample Time - minutes	120	120	120	120	120	120	120	120
Barometric Pressure - " Hg	29.56	29.56	29.62	29.62	29.60	29.60	29.59	29.59
Static Pressure - " H ₂ O	-11.34	-9.50	-11.03	-8.88	-9.79	-12.00	-10.72	-10.13
% Oxygen -	5.1	7.4	4.4	7.0	4.5	6.3	4.6	6.9
% Carbon Dioxide -	15.0	12.8	15.7	13.2	15.7	13.8	15.5	13.3
% N ₂ + CO -	79.9	79.8	79.9	79.8	79.9	79.8	79.9	79.8
Stack Temp (Dry Bulb) - °F	230	210	233	215	234	219	233	215
Stack Temp (Wet Bulb) - °F	230.3	209.8	233.0	215.2	234.5	218.7	232.6	214.6
"S" sample (rms vel head) - " H ₂ O	0.346	0.387	0.352	0.398	0.338	0.381	0.345	0.389
Dust Wt. - gm	8.3371	0.1553	7.7962	0.8161	7.8769	0.6084	8.0034	0.5266
Sample Volume - DSCF	46.79	79.35	46.38	79.94	44.33	77.65	45.83	78.98
Sample Volume - dscm	1.325	2.247	1.314	2.264	1.255	2.199	1.298	2.237
ABS ST PRES - " Hg	28.73	28.86	28.81	28.97	28.88	28.72	28.81	28.85
ABS ST TEMP - °R	690	670	693	675	694	679	693	675
H ₂ O - % by Vol - vapor	7.8	6.7	8.4	7.1	9.0	7.7	8.4	7.2
Water Volume - std ft ³	3.97	5.67	4.25	6.07	4.38	6.52	4.20	6.08
Dry Molecular Weight - lb/lb-mole	30.61	30.34	30.69	30.39	30.68	30.47	30.66	30.40
Wet Molecular Weight - lb/lb-mole	29.62	29.52	29.62	29.52	29.54	29.50	29.59	29.51
% EXCESS AIR -	31.6	54.3	26.5	50.1	26.7	42.9	28.3	49.1
Dry Mole Frac. -	0.922	0.933	0.916	0.929	0.910	0.923	0.916	0.928
Wet Mole Frac. -	0.078	0.067	0.084	0.071	0.090	0.077	0.084	0.072
Gas Velocity, Direct - ft/sec	37.46	37.54	37.80	38.15	37.08	37.60	37.45	37.76
ACFM -	1225	1227	1236	1248	1213	1229	1225	1235
DSCFM -	829	871	831	878	810	847	823	865
DSCFM (rounded) -	800	900	800	900	800	800	800	866.6667
DSCMM -	23	25	24	25	23	24	23	25
Excess Air Free DSCFM -	628	562	655	583	637	590	640	578
CALCULATED FIRING RATE:								
Dry - lb/min	5	4	5	4	5	4	5	4
Wet - lb/min	5	4	5	4	5	4	5	4
Dry - lb/hr	279	250	291	259	283	262	284	257
Wet - lb/hr	285	255	297	265	289	268	291	263
CALCULATED FIRING RATE:								
Dry - tons/hr	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wet - tons/hr	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
HEAT INPUT:								
MM Btu/hr -	4	4	4	4	4	4	4	4
PARTICULATE LOADING:								
Grains/DSCF -	2.7493	0.0302	2.5935	0.1575	2.7420	0.1209	2.6949	0.1029
lb/hr -	18.86	0.23	17.79	1.22	18.81	0.83	18.49	0.76
lb/MM Btu -	4.81	0.07	4.36	0.33	4.75	0.23	4.64	0.21
								#DIV/0!
Ash Production - lb/hr	20	18	20	19	21	19	20	19
Bagouse Ash	19	0.23	18	1.22	19	0.83	18.49	0.76
Bottom Ash	1	17	3	18	2	19	2	18
Percent Fly Ash	95.9%	1.3%	86.8%	6.5%	89.6%	4.3%	90.8%	4.0%
% ISOKINETIC -	104.7	99.7	103.6	99.7	101.5	100.3	103.3	99.9

Table 2. Analyses of Mg(OH)₂ Slurry

Analytical Number	Sample Number	Date	Mg(OH) ₂ Slurry Description	SOLIDS ANALYSIS													LIQUIDS ANALYSIS			Slurry Injection Rate	Flue Gas Flow Rate	SO ₃ in Flue Gas (wet)
				As Det. Moisture	SiO ₂	Al ₂ O ₃	TiO ₂	Fe ₂ O ₃	CaO	MgO	Na ₂ O	K ₂ O	P ₂ O ₅	SO ₃	As Det. Hg	Slurry %Solids	Ca	Mg	Hg			
				%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	ppm	(dry)%	mg/L	mg/L	NG/ML	lb/hr	lb/hr	PPMv
			Mitchell Task 5																			
20042142	61	3/24/04	DILUTE (FROM PUMP)	3.40	3.01	0.97	0.04	0.30	5.41	58.02	0.07	0.00	0.03	5.25	0.89	4.00	577	197	<1.0	103	14000	30
20042143	62	3/24/04	DILUTE (FROM LINE)	3.34	3.52	0.96	0.07	0.31	5.59	55.30	0.02	0.23	0.02	6.11	0.83	3.90	617	205	<1.0	103	14000	30
20042144	69	3/25/04	DILUTE (FROM LINE)	2.57	3.18	0.93	0.07	0.30	5.70	56.25	0.01	0.24	0.01	6.52	0.92	3.60	611	151	<1.0	103	14000	30
20042145	70	3/25/04	DILUTE (FROM PUMP)	3.44	3.11	0.94	0.08	0.29	5.06	56.28	0.01	0.11	0.02	5.72	0.90	3.70	640	155	<1.0	103	14000	30
			Mitchell Task 6																			
20042146	74	4/1/04	DILUTE (FROM LINE)	2.35	3.01	0.92	0.07	0.29	6.66	55.12	0.01	0.07	0.02	7.76	0.91	3.40	650	131	<1.0	103	14000	30
20042147	81	4/13/04	DILUTE (FROM PUMP)	2.83	3.11	0.98	0.09	0.31	4.97	57.27	0.04	0.13	0.01	5.49	0.92	3.30	663	154	<1.0	103	14000	30
20042148	83	4/13/04	DILUTE (FROM LINE)	2.88	2.97	0.93	0.08	0.30	5.45	56.54	0.05	0.08	0.03	6.09	0.91	3.20	632	157	<1.0	103	14000	30

**All percentages are based on weight*

Table 3. Analyses of Coal and Flyash

TASK 5									
ANALNUM	SAMPLE	DATE	DESCR	MOIST	Dry Basis				As Det.
				%	ASH	C	S	CL	Hg
					%	%	%	%	ppm
20041589	58	3/24/04	MITCHELL COAL	1.78	11.21	72.73	4.14	0.060	0.11
20041594	65	3/25/04	MITCHELL COAL	1.80	10.43	73.72	4.35	0.070	0.11
20041595	66	3/25/04	MITCHELL COAL	1.88	9.75	74.08	4.26	0.060	0.11
20041590	59	3/24/04	PILOT - MITCHELL FLY ASH	1.98	92.64	5.95			0.62
20041591	60	3/24/04	STATION - MITCHELL FLY ASH	0.15	90.21	8.65			0.30
20041592	63	3/25/04	PILOT - MITCHELL FLY ASH	2.48	91.10	8.39			0.85
20041593	64	3/25/04	STATION - MITCHELL FLY ASH	0.16	89.14	9.48			0.27
20041596	67	3/25/04	PILOT - MITCHELL FLY ASH	1.66	90.26	8.59			0.80
43369			"Repeat"		90.32	8.52			0.80
20041597	68	3/25/04	STATION - MITCHELL FLY ASH	0.16	89.62	8.89			0.23
TASK 6									
				%	%	%	%	%	ppm
20041727	71	4/1/04	MITCHELL COAL	1.73	9.33	73.79	4.08	0.05	0.09
20041862	75	4/13/04	MITCHELL COAL	2.16	9.38	70.90	4.66	0.05	0.11
20041863	80	4/13/04	MITCHELL COAL	2.11	9.55	70.32	4.78	0.06	0.11
20041728	72	3/30/04	PILOT - MITCHELL FLY ASH	1.05	92.47	6.49			0.37
20041729	73	4/1/04	STATION - MITCHELL FLY ASH	0.47	88.33	10.81			0.10
20041858	76	4/13/04	PILOT - MITCHELL ESP ASH	2.49	87.40	11.02			0.87
20041859	77	4/13/04	STATION - MITCHELL ESP ASH	0.26	88.22	11.41			0.21
20041860	78	4/13/04	PILOT - MITCHELL ESP ASH	2.58	88.73	9.83			0.86
20041861	79	4/13/04	STATION - MITCHELL ESP ASH	0.27	86.59	12.72			0.23
20042133	82	4/13/04	PILOT - MITCHELL ESP ASH	1.91	89.44	7.54			0.56

Table 4. Hg Sampling – Ontario Hydro Sampling Train Data
TASK 6 – Humidification Tests

Location	E	F	G	E	F	G	E	F	G
Date	4/1/04	4/1/04	4/1/04	4/13/04	4/13/04	4/13/04	4/13/04	4/13/04	4/13/04
Start Time	15:15	15:15	15:15	10:55	10:55	10:55	15:15	15:15	15:15
Stop Time	17:36	17:36	17:36	13:15	13:15	13:15	17:28	17:28	17:28
Test Number	E-6-1	F-6-1	G-6-1	E-6-2	F-6-2	G-6-2	E-6-3	F-6-3	G-6-3
Sample Type	OH-Hg	OH-Hg	OH-Hg	OH-Hg	OH-Hg	OH-Hg	OH-Hg	OH-Hg	OH-Hg
Y factor of dry gas meter -	1.006	1.038	0.984	1.006	1.038	0.984	1.006	1.038	0.984
Gas Volume - ft ³	56.01	44.01	80.69	55.75	42.03	83.46	56.26	41.99	78.41
Delta H of dry gas meter - " H ₂ O	0.82	0.47	1.98	0.84	0.43	1.70	0.84	0.43	1.70
Meter Temperature - °F	57.8	64.3	58.8	61.5	66.0	61.4	60.0	68.9	61.0
C Factor of pitot tube -	0.790	0.806	0.796	0.790	0.806	0.796	0.790	0.806	0.796
Nozzle Diameter - inches	0.251	0.212	0.276	0.251	0.212	0.276	0.251	0.212	0.276
A n (area of nozzle) - ft ²	0.00034	0.00025	0.00042	0.00034	0.00025	0.00042	0.00034	0.00025	0.00042
Area of Stack (Single of Du - ft ²	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
H ₂ O Weight - gm	129.2	100.3	153.1	109.3	104.7	181.6	112.4	106.1	183.0
Sample Time - minutes	120	120	120	120	120	120	120	120	120
Barometric Pressure - " Hg	28.86	28.86	28.86	28.96	28.96	28.96	28.82	28.82	28.82
Static Pressure - " H ₂ O	-7.80	-8.60	-9.50	-8.50	-9.37	-9.50	-8.90	-10.11	-9.90
% Oxygen -	6.9	5.9	7.8	4.3	4.1	6.0	4.9	3.8	6.3
% Carbon Dioxide -	13.3	14.3	12.4	15.8	16.0	14.1	15.2	16.3	13.9
% N ₂ + CO -	79.8	79.9	79.8	79.9	80.0	79.9	79.9	80.0	79.8
Stack Temp (Dry Bulb) - °F	287	249	219	293	249	220	292	250	220
Stack Temp (Wet Bulb) - °F	125.0	123.3	125.0	125.0	123.3	125.0	125.0	123.3	125.0
"S" sample (rms vel head) - " H ₂ O	0.310	0.354	0.378	0.342	0.327	0.429	0.341	0.332	0.450
Dust Wt. - gm	6.7468	7.7107	0.1568	11.2145	5.9848	0.0438	7.0259	6.4353	0.0687
Sample Volume - DSCF	55.51	44.41	78.31	55.05	42.42	80.81	55.45	41.94	75.61
Sample Volume - dscm	1.572	1.258	2.218	1.559	1.201	2.289	1.570	1.188	2.141
ABS ST PRES - " Hg	28.29	28.23	28.16	28.34	28.27	28.26	28.17	28.08	28.09
ABS ST TEMP - °R	747	709	679	753	709	680	752	710	680
H ₂ O - % by Vol - vapor	9.9	9.6	8.4	8.6	10.4	9.6	8.7	10.6	10.2
Water Volume - std ft ³	6.09	4.72	7.21	5.15	4.93	8.55	5.29	5.00	8.62
Dry Molecular Weight - lb/lb-mole	30.40	30.52	30.30	30.70	30.72	30.50	30.63	30.75	30.48
Wet Molecular Weight - lb/lb-mole	29.18	29.31	29.26	29.61	29.39	29.30	29.53	29.39	29.20
% EXCESS AIR -	48.7	38.6	58.6	25.6	23.9	39.8	30.3	21.6	42.5
Dry Mole Frac. -	0.901	0.904	0.916	0.914	0.896	0.904	0.913	0.894	0.898
Wet Mole Frac. -	0.099	0.096	0.084	0.086	0.104	0.096	0.087	0.106	0.102
Gas Velocity, Direct - ft/sec	35.76	37.94	37.99	37.40	36.39	40.40	37.50	36.82	41.56
ACFM -	1169	1241	1242	1223	1190	1321	1226	1204	1359
DSCFM -	705	788	832	743	750	876	740	751	889
DSCFM (rounded) -	700	800	800	700	800	900	700	800	900
DSCMM -	20	22	24	21	21	25	21	21	25
Excess Air Free DSCFM -	472	567	522	590	604	625	567	616	622
CALCULATED FIRING RATE:									
Dry - lb/min	3	4	4	4	4	5	4	5	5
Wet - lb/min	4	4	4	4	5	5	4	5	5
Dry - lb/hr	210	252	232	263	269	278	252	274	276
Wet - lb/hr	214	257	237	268	274	284	257	280	282
CALCULATED FIRING RATE:									
Dry - tons/hr	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wet - tons/hr	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
HEAT INPUT:									
MM Btu/hr -	3	4	3	4	4	4	4	4	4
PARTICULATE LOADING:									
Grains/DSCF -	1.8752	2.6790	0.0309	3.1431	2.1771	0.0084	1.9550	2.3675	0.0140
lb/hr -	11.26	18.38	0.21	18.87	14.93	0.06	11.73	16.24	0.11
lb/MM Btu -	3.83	5.20	0.07	5.12	3.96	0.02	3.34	4.25	0.03
Ash Production - lb/hr	15	18	16	19	19	20	19	20	20
Bagouse Ash	11	18	0.21	19	15	0.06	12	16	0.11
Bottom Ash	4	-1	16	0	4	20	7	4	20
Percent Fly Ash	76.2%	103.6%	1.3%	99.5%	79.0%	0.3%	62.9%	80.0%	0.5%
% ISOKINETIC -	104.3	104.5	103.0	98.0	104.8	100.9	99.1	103.6	93.0

Table 5. Analyses of Pilot Fly Ash and Magnesium Hydroxide Slurry Samples

As Determined Basis																	
		Mg/SO ₃	ESP inlet	MOIST	ASH	C	SiO ₂	Al ₂ O ₃	TiO ₂	Fe ₂ O ₃	CaO	MgO	Na ₂ O	K ₂ O	P ₂ O ₅	SO ₃	Hg
Sample	Date	mol. ratio	T, deg F	% as det.	%, dry	% dry	%	%	%	%	%	%	%	%	%	%	mg/kg
Pilot flyash	1/29/04	0	295	1.05	92.97	7.15	47.57	21.52	1.01	14.84	4.29	0.76	0.61	1.76	0.36	1.06	0.32
Pilot flyash	2/24/04	1.9	236	0.40	90.86	8.42	48.45	21.83	1.01	11.79	3.39	1.11	0.7	1.85	0.26	0.96	0.67
Pilot flyash	3/25/04	3.7	221	2.48	91.10	8.39	41.8	19.35	0.87	20.3	2.65	1.59	0.53	1.5	0.14	2.28	0.85
Slurry, oven dried*	2/24/04	1.9	236	3.22	-	-	3.21	0.98	0.03	0.32	3.34	60.13	0.06	0.01	0.04	3.62	0.90
Slurry, oven dried**	3/25/04	3.7	221	3.01	-	-	3.15	0.94	0.08	0.30	5.38	56.27	0.01	0.18	0.02	6.12	0.91

* original slurry sample contained 1.80% solids
 **original slurry sample contained 3.65% solids, values shown are averages of two samples for this date

Rev: 8/20/2004

Table 6. SO₃ Concentrations Measured at Various Locations Around Pilot Air Heater

All SO₃ concentrations are in units of ppmv of gas and are corrected for air to 0% oxygen

Date (ratio)		3/2/04 (1.9/1 Mg/SO ₃)				3/3/04 (4/1 Mg/SO ₃)			
Sampling Location		Trial 1		Trial 2		Trial 1		Trial 2	
designation	name	gas	filter	gas	filter	gas	filter	gas	filter
A	Economiser outlet	33.3	</= 0.2	29.5	</= 0.2	34.3	</= 0.2	30.7	</= 0.2
H	Air heater gas inlet	10.2	</= 0.3	3.3	</= 0.2	2.1	</= 0.2	1.4	</= 0.2
B	Air heater gas outlet	1	ND	1.5	</= 0.3	0.8	</= 0.2	0.6	</= 0.2
D	Air heater air outlet	25.8	</= 2.9	31.3	</= 2.6	8.5	</= 4.2	4.4	</= 2.2

ND = Not determined; filter sample not recovered

rev: 9/13/04

Figure 1. Diagram of Pilot Plant Showing Sampling Locations “A” Through “H”

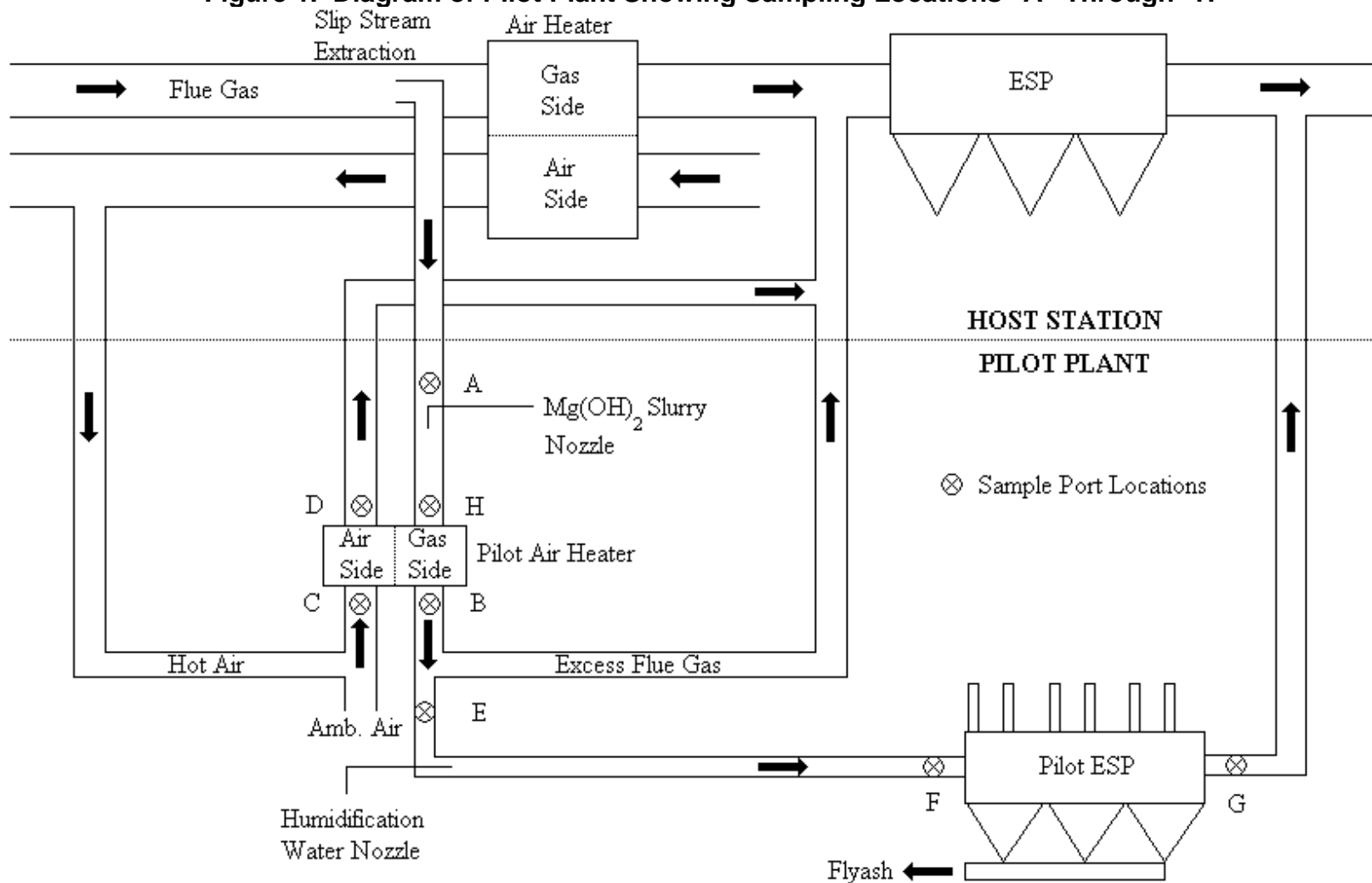
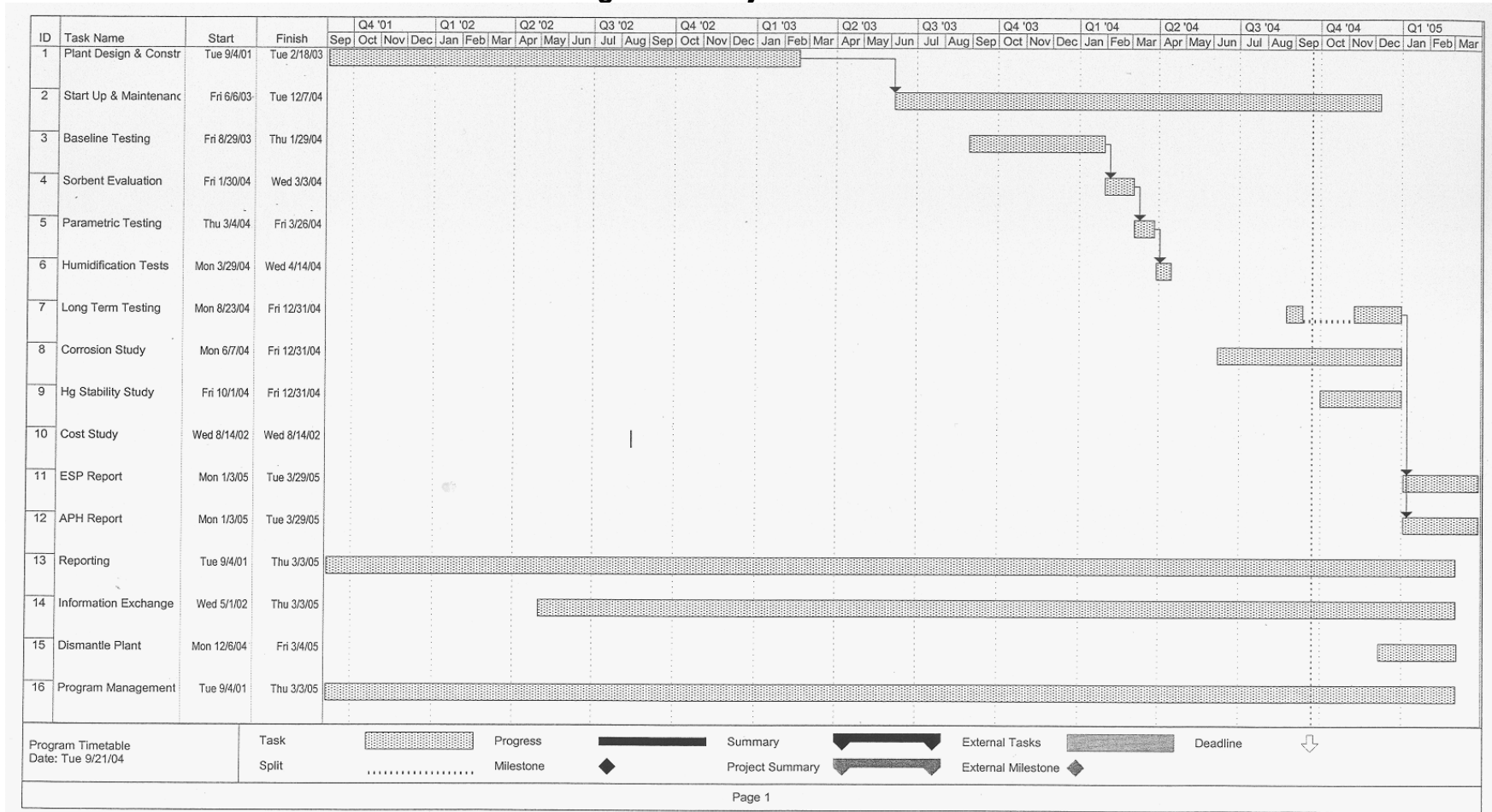


Figure 2. Project Timetable



ATTACHMENT A

**Presentation:
DOE Mercury Control Technology R&D Program Review Meeting in Pittsburgh on
July 14 and 15, 2004**

ATTACHMENT A

THE CONSOL/ALLEGHENY PILOT PLANT STUDY OF LOW-TEMPERATURE MERCURY CAPTURE WITH AN ELECTROSTATIC PRECIPITATOR

R. A. Winschel, M. L. Fenger



CONSOL Energy Inc.

K. H. Payette

Allegheny Energy Supply Co., LLC

DOE/NETL Mercury Control Technology R&D Program Review Meeting,
Pittsburgh, July 14, 2004

Slide 1

HOST PLANT Allegheny Energy Mitchell Station

- Courtney, PA
- 288 MW Unit 3
- In service 1963
- Thiosorbic lime wet FGD, ESP, no SCR
- Fired with eastern bituminous coal
S 3.0 - 4.8% Ash 9.3 - 15%
Cl 0.05 - 0.09% Hg 0.09 - 0.13 ppm

*Analyses on dry basis, except Hg as determined

Slide 4

CONCEPT

- Absorb Hg on particulate by cooling flue gas to 225-240 °F with air heater or water spray
- Collect particulate with ESP to remove Hg
- Protect against acid corrosion by introducing $Mg(OH)_2$ into flue gas upstream of heater

Slide 2

ALLEGHENY MITCHELL STATION



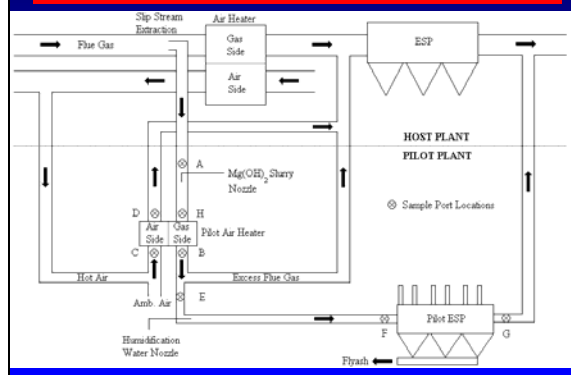
Slide 5

POTENTIAL BENEFITS OF TECHNOLOGY TO BE EXAMINED

- 70-90% Hg removal targeted
- Projected cost (\$/lb Hg) is order of magnitude lower than carbon injection
- Suitable for retrofit or new plants
- Potentially suitable for the full range of coal types
- Effective SO_3 reduction
 - ▶ Visible plume mitigation
 - ▶ TRI reduction
 - ▶ SCR/SNCR benefits
 - ▶ Secondary fine particulate reduction
- Potential to improve heat rate by 2%
 - ▶ 2% reduction in NO_x , SO_2 , CO, particulate and CO_2
 - ▶ ~ \$600,000/y fuel cost savings for 600 MW plant

Slide 3

PILOT PLANT PROCESS SCHEMATIC



Slide 6

PILOT AIR HEATER

Slide 7

EFFECTIVENESS OF $Mg(OH)_2$ INJECTION FOR SO_3 CONTROL

Mg:SO ₃ Mole Ratio	SO ₃ Concentration, ppmv (Acid Dew point, °F) at Location		
	Before Mg Injection	After Mg Injection, Before Air Heater	Air Heater Exhaust
None	12.5 (274)	-	2.1 (237)
1.9/1	31.4 (287)	6.8 (256)	1.2 (230)
4.0/1	32.5 (288)	1.8 (236)	0.7 (222)

Slide 10

PILOT ESP

Slide 8

MERCURY CAPTURE BY ESP

Test	Mg:SO ₃ Mole Ratio	Temp., °F AH Exhaust	Temp., °F ESP Inlet	Hg Capture by ESP, mass % (each test)	Hg Capture by ESP, mass % avg. ± std. dev. (best values)
Baseline	0/1	320	290	9* / 14 / 39	26 ± 18
Mg(OH) ₂ , AH Cooling	1.9/1	250	235	40 / 31 / 29	34 ± 6
Mg(OH) ₂ , AH Cooling	3.5/1	234	220	48 / 35 / 83*	42 ± 9
Mg(OH) ₂ , WS Cooling	3.4/1	312	240	17* / 48 / 50	49 ± 1

*Poor/no Hg mass balance, not in average

Slide 11

EXPERIMENTAL PLAN

- Max. flue gas flowrate: 16,500 lb/h (1.7 MW)
- Mg/SO₃ molar ratio: 2/1 - 4/1
- Gas temperature at ESP inlet: 220 - 315 °F
- Water spray cooling: on/off
- Gas sampling for Hg, particulate, SO₂, SO₃
- Speciate Hg at inlet/outlet of air heater and ESP
- Evaluate air heater and ESP performance and corrosion
- Evaluate stability of captured Hg

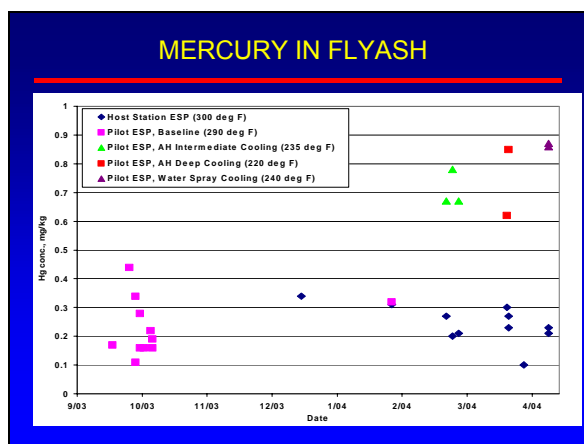
Slide 9

LOSS OF MERCURY ACROSS AIR HEATER

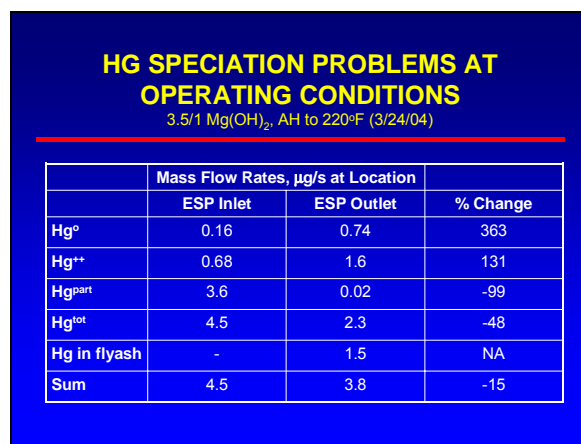
- Two tests at baseline conditions: no Mg(OH)₂, 315°F
- 39% and 12% mercury lost across air heater
- We presume it recycles with heated air, similarly to SO₃

Slide 12

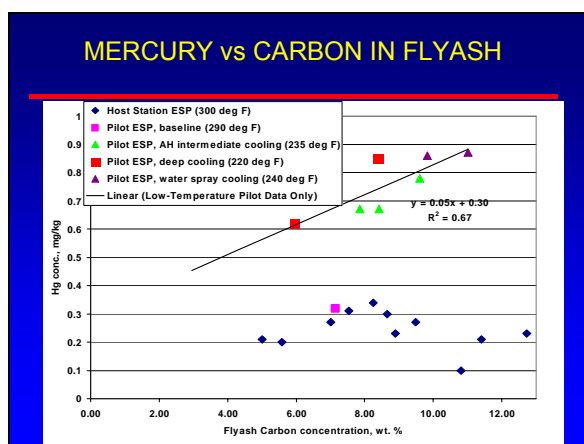
ATTACHMENT A



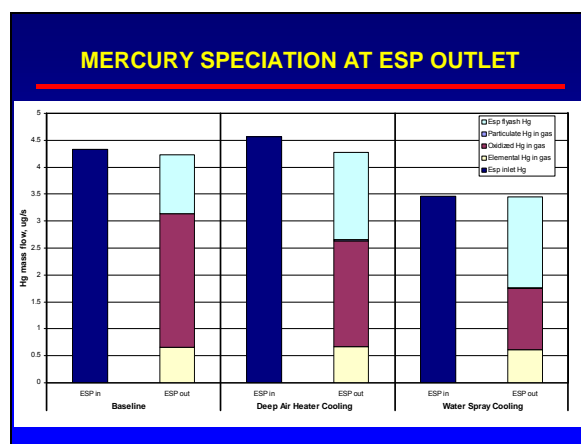
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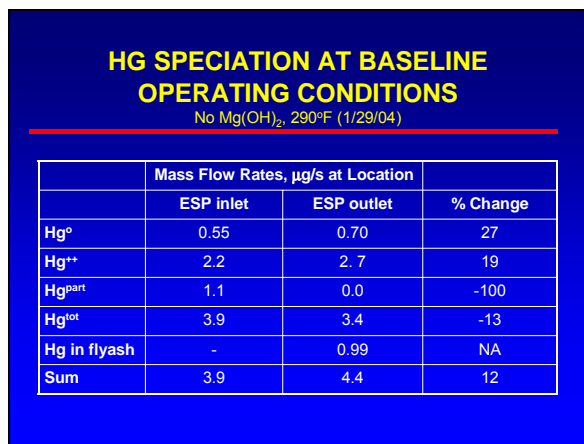
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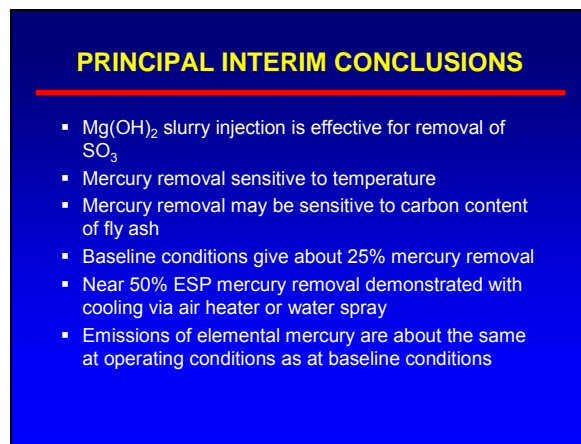
Slide 14



Slide 17



Slide 15



Slide 18

ADDITIONAL INTERIM CONCLUSIONS

- Ontario Hydro method appears to suffer problems with high-dust streams at temperatures of $\sim 250^{\circ}\text{F}$
- Some mercury lost in air heater; we presume it recycles with heated air, similarly to SO_3
- No increase in pilot air heater ΔP after 84 h total operation with sorbent injection
- Pilot ESP has performed satisfactorily with $\text{Mg}(\text{OH})_2$ injection at reduced temperature

Slide 19

PROJECT PLANS AS OF JULY 14, 2004

- Long-term testing - rest of 2004
- Evaluation of air heater and ESP performance and corrosion
- Evaluation of mercury stability in flyash
- Project completion 3/05

Slide 20

ACKNOWLEDGEMENT

- US DOE, NETL, CA No. DE-FC26-01NT41181 (Lynn Brickett)
- Alstom Power, Inc.
- Environmental Elements Corp.
- Carmeuse Lime, Inc.
- J. A. Withum, J. E. Locke, M. M. Majireck

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ATTACHMENT B

Presentation:

**Power Plant Air Pollution Control “Mega” Symposium, held August 30 through
September 2, 2004**

ATTACHMENT B

CONTROL OF MERCURY EMISSIONS BY ABSORPTION ON FLYSASH – EXPERIMENTAL RESULTS OF THE CONSOL/ALLEGHENY PILOT PLANT PROGRAM

R. A. Winschel, M. L. Fenger - CONSOL Energy Inc.
K. H. Payette - Allegheny Energy Supply Co., LLC
L. A. Brickett – National Energy Technology
Laboratory, US DOE

Power Plant Air Pollution Control "Mega" Symposium,
Washington, DC, August 30, 2004

Slide 1

HOST PLANT

Allegheny Energy Mitchell Station

- Courtney, PA
- 288 MW Unit 3, corner fired
- In service 1963
- Thiosorbic lime wet FGD, ESP, no SCR
- Fired with eastern bituminous coal
 - S 3.0 - 4.8% Ash 9.3 – 15%
 - Cl 0.05 - 0.09% Hg 0.09 - 0.13 ppm

*Analyses on dry basis, except Hg as determined

Slide 4

CONCEPT

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- Collect particulate with ESP to remove Hg
- Protect against acid corrosion by introducing $Mg(OH)_2$ into flue gas upstream of heater

Slide 2

ALLEGHENY MITCHELL STATION



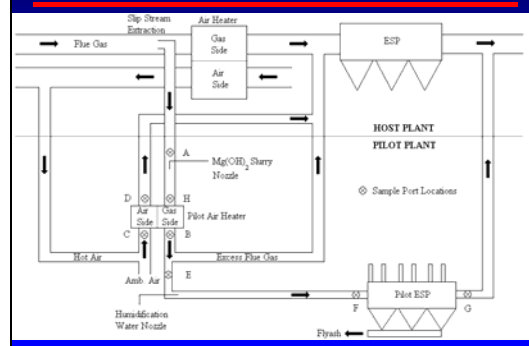
Slide 5

POTENTIAL BENEFITS OF TECHNOLOGY TO BE EXAMINED

- 70-90% Hg removal targeted
- Projected cost (\$/lb Hg) is order of magnitude lower than carbon injection
- Suitable for retrofit or new plants
- Potentially suitable for the full range of coal types
- Effective SO_3 reduction
 - ▶ Visible plume mitigation
 - ▶ TRI reduction
 - ▶ SCR/SNCR benefits
 - ▶ Secondary fine particulate reduction
- Potential to improve heat rate by 2%
 - ▶ 2% reduction in NO_x , SO_2 , CO, particulate and CO_2
 - ▶ ~ \$600,000/y fuel cost savings for 600 MW plant

Slide 3

PILOT PLANT PROCESS SCHEMATIC



Slide 6

ATTACHMENT B

PILOT AIR HEATER



Slide 7

EFFECTIVENESS OF $Mg(OH)_2$ INJECTION FOR SO_3 CONTROL

Mg:SO ₃ Mole Ratio	SO ₃ Concentration, ppmv (Acid Dew point, °F) at Location		
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Slide 10

PILOT ESP



Slide 8

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Slide 11

EXPERIMENTAL PLAN

- Max. flue gas flowrate: 16,500 lb/h (1.7 MW)
- Mg/SO₃ molar ratio: 2/1 - 4/1
- Gas temperature at ESP inlet: 220 - 315 °F
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- Speciate Hg at inlet/outlet of air heater and ESP
- Evaluate air heater and ESP performance and corrosion
- Evaluate stability of captured Hg

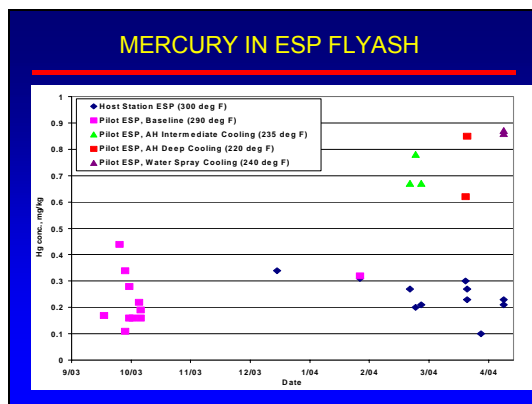
Slide 9

LOSS OF MERCURY ACROSS AIR HEATER

- Two tests at baseline conditions: no Mg(OH)₂, 315°F
- 39% and 12% mercury lost across air heater
- Consistent with other observations of mercury recycling with heated air, similarly to SO₃

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ATTACHMENT B



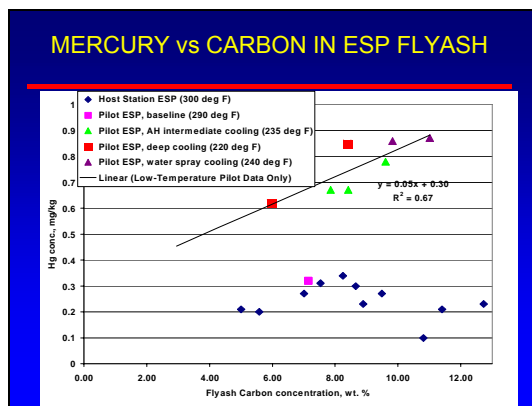
Slide 13

PROBLEMS WITH HG SPECIATION VIA OH METHOD AT OPERATING CONDITIONS

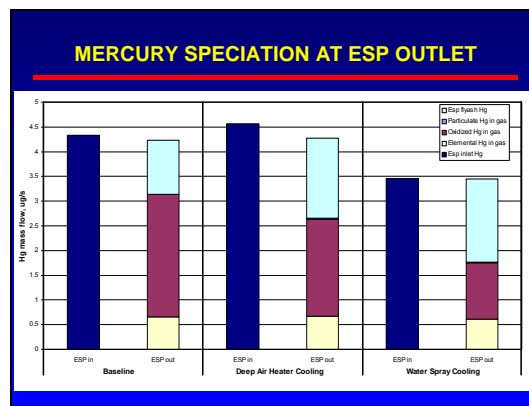
3.5/1 Mg(OH)₂, AH to 220°F (3/24/04)

	Mass Flow Rates, µg/s at Location		% Change
	ESP Inlet	ESP Outlet	
Hg ^o	0.16	0.74	363
Hg ⁺⁺	0.68	1.6	131
Hg ^{part}	3.6	0.02	-99
Hg ^{tot}	4.5	2.3	-48
Hg in ESP flyash	-	1.5	NA
Sum	4.5	3.8	-15

Slide 16



Slide 14



Slide 17

HG SPECIATION VIA OH METHOD AT BASELINE CONDITIONS

No Mg(OH)₂, 290°F (1/29/04)

	Mass Flow Rates, µg/s at Location		% Change
	ESP inlet	ESP outlet	
Hg ^o	0.55	0.70	27
Hg ⁺⁺	2.2	2.7	19
Hg ^{part}	1.1	0.0	-100
Hg ^{tot}	3.9	3.4	-13
Hg in ESP flyash	-	0.99	NA
Sum	3.9	4.4	12

Slide 15

- ### PRINCIPAL INTERIM CONCLUSIONS
- Mg(OH)₂ slurry injection is effective for removal of SO₃
 - Mercury removal sensitive to temperature
 - Mercury removal may be sensitive to carbon content of fly ash
 - Baseline conditions give about 25% mercury removal
 - Near 50% ESP mercury removal demonstrated with cooling via air heater or water spray
 - Emissions of elemental mercury are about the same at operating conditions as at baseline conditions

Slide 18

ADDITIONAL INTERIM CONCLUSIONS

- Ontario Hydro method appears to suffer problems with high-dust streams at temperatures $\geq 250^{\circ}\text{F}$
- Some mercury lost in air heater; consistent with it recycling with heated air, as seen elsewhere
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Slide 19

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Slide 20

ACKNOWLEDGEMENT

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- Alstom Power, Inc.
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**Control of Mercury Emissions By Absorption on Flyash – Experimental Results of
the CONSOL/Allegheny Pilot Plant Program**

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ABSTRACT

This paper presents experimental results from pilot-scale tests of CONSOL Energy's technology for reducing mercury and sulfur trioxide emissions from coal-fired power plants. The technology works by cooling the exhaust gases with an air heater (or water spray) to 220 to 250 °F, thereby promoting the absorption of mercury on the coal flyash; the flyash is then captured in the particulate collection device. Magnesium hydroxide slurry is injected to prevent corrosion from acid condensation. The performance of the process is being evaluated at a 3640 scfm (1.7 MWe equivalent) slip-stream pilot plant at the Allegheny Energy Supply Mitchell Station with support from DOE National Energy Technology Laboratory. Other participants include Alstom Power Inc., Environmental Elements Corp., and Carmeuse Lime, Inc. The performance of the process and the impacts of temperature, magnesium hydroxide slurry injection, and cooling method on mercury and sulfur trioxide capture are described.

INTRODUCTION

Background

Coal-fired electric generating plants are the largest remaining unregulated source of anthropogenic mercury (Hg) emissions in the U.S. There currently are several legislative and regulatory initiatives for reducing these emissions. Under the 1990 Amendments to the Clean Air Act (CAA), the U.S. Environmental Protection Agency (EPA) issued draft regulations on December 15, 2003, to reduce Hg emissions from coal-fired power plants. EPA proposed three alternative regulatory approaches, including a maximum achievable control technology (MACT) approach, a CAA section 112(n)(1) cap and trade approach, and a CAA section 111(d) cap and trade approach. Final regulations are to be issued before April 2005. The implementation schedule is

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dependent on which regulatory approach is selected for the final rule. For example, if the MACT approach is selected, then the compliance date is April 2008. If the section 111(d) approach is selected, then the compliance date is January 2010. Another initiative is the Administration's proposed Clear Skies Initiative, under which Hg emissions from coal-fired power plants will be reduced from 48 ton in 1999 to 34 ton by 2010, and to 15 ton by 2018 under a cap and trade system. The U.S. Congress is considering mandating reductions that are deeper and more rapid than the Administration's proposal. In addition, several States are instituting programs for reducing Hg emissions within their borders.

Technologies are available to reduce Hg emissions from coal-fired power plants, although no technology currently available eliminates Hg emissions uniformly across the spectrum of power plant configurations. The current leading technology is powdered activated carbon (PAC) injection, also known as activated carbon injection (ACI). Authors from the U.S. Department of Energy (DOE) and EPA project control costs via PAC injection for most plants to be 0.3-1.9 mills/kWh.ⁱ This is equivalent to \$4,500 to \$29,000 per pound of mercury controlled at a plant burning 12,000 Btu/lb coal containing 0.1 ppm Hg at a heat rate of 10,000 Btu/kWh, and equipped to control 80% of the mercury emissions. In addition to these high control costs, PAC injection contaminates the flyash with carbon such that the flyash cannot be used in concrete. Moreover, the process is not well proven on coal plants. Other pollution control technologies can remove Hg from flue gases as a "co-benefit." For example, flue gas desulfurization (FGD) systems in combination with electrostatic precipitators (ESPs) can reduce smoke stack mercury emissions from units firing bituminous coal by 50% to 70% (typically about 65%).ⁱⁱ Available information suggests that the combination of selective catalytic reduction (SCR) with FGD and ESP systems can provide ~75-90% Hg emissions reduction, but the actual range is uncertain.

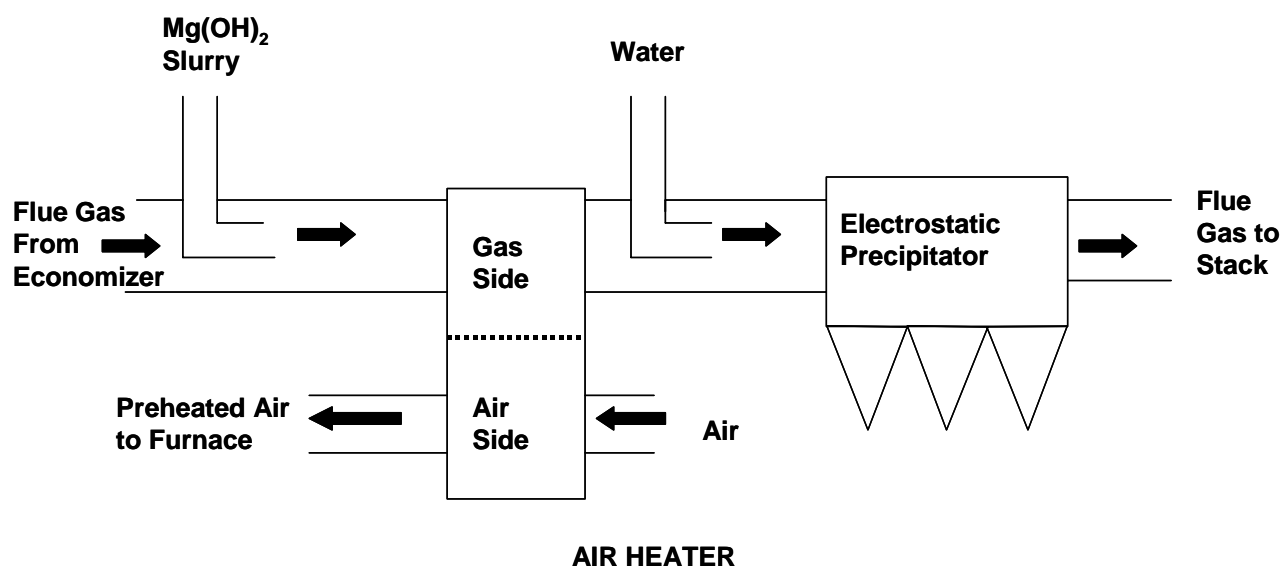
DOE is co-funding the development and testing of alternative technologies that may be effective and less expensive than PAC injection. One of these technologies under development is the subject of this paper. CONSOL Energy and Allegheny Energy Supply, with support from the U.S. Department of Energy's National Energy Technology Laboratory, are conducting a three-year program to construct and operate a pilot plant using flue gas from a coal-fired power generating station to develop the innovative technology for reducing mercury emissions from coal-fired power plants. Other participants are Alstom Power Inc., Environmental Elements Corp., and Carmeuse Lime, Inc. The technology works by cooling the exhaust gases and permitting the mercury to absorb on the coal flyash. The flyash and mercury are then captured in the power plant's existing particulate collection device. An alkaline material is injected to prevent corrosion of the power plant's air heater and ductwork. In addition to controlling mercury emissions, the technology will reduce the emissions of sulfur trioxide and ameliorate the visible plume problem sometimes associated with selective catalytic reduction applications. The technology can also allow improved generating efficiency, which would lead to lower emissions of most pollutants and carbon dioxide. The test program includes a series of short-term tests to determine performance, long-term tests to evaluate the impact of the technology on the performance of specific power station

components, and mercury stability tests on the collected flyash.

Process Concept and Experimental Goals

The concept behind this technology is to absorb mercury (Hg) onto the existing particulate (i.e., flyash) by cooling the flue gas to 220-240 °F with the air heater or with water sprays. The mercury on the flyash is then captured in the power plant's existing particulate collection device. An alkaline material, magnesium hydroxide ($\text{Mg}(\text{OH})_2$), is injected into flue gas upstream of the air heater to control sulfur trioxide (SO_3), which prevents acid condensation and corrosion of the power plant air heater and ductwork. See Figure 1.

Figure 1. Conceptual Schematic of Mercury Control Process



CONSOL's prior development work suggested that this concept could be successful for controlling Hg emissions. Tests on the CONSOL pilot-scale combustor gave as much as 90% Hg removal when firing Illinois coal, depending on gas temperature and ash carbon content.ⁱⁱⁱ Bench-scale work conducted by CONSOL showed that FGD by-product $\text{Mg}(\text{OH})_2$ slurry is an active sorbent for SO_3 at economizer outlet temperatures.^{iv}

There are several potential benefits of the technology. The most important one is that the technology could provide 70-90% Hg removal at a projected cost an order of magnitude lower (on a \$/lb Hg removed basis) than PAC injection. The technology is conceptually suitable for retrofitting to existing plants or for new plants. The technology has potential applicability to the full range of coal types. In addition to controlling Hg emissions, the technology will reduce the emissions of SO_3 , a precursor of secondary fine particulate matter. This will reduce emissions reportable under the Toxic Release Inventory, and ameliorate any associated visible plume problem. The removal of SO_3 also benefits the use of SCR and selective non-catalytic reduction installations by preventing the formation of ammonium bisulfate fouling deposits, which are sometimes

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problematic with these technologies. For those power stations equipped with a sufficiently large air heater, the technology can also allow approximately 2% improved generating efficiency, which would lead to 2% lower emissions (on a lb/kWh basis) of most pollutants and carbon dioxide. The improved efficiency could lead to savings in fuel cost of ca. \$600,000/y for 600 MW plant; this would essentially offset the costs of the $\text{Mg}(\text{OH})_2$.

The goals of the pilot plant program are to:

- Determine the ability of the process to remove Hg and to evaluate Hg removal by species
- Determine the optimum operating conditions for cost-effective Hg control
- Determine the optimum sorbent rate for cost-effective SO_3 control
- Determine the impact of reduced cold-end temperature and SO_3 control on air heater and ESP performance and corrosion
- Determine the stability toward leaching and volatilization of the captured Hg
- Disseminate project information

EXPERIMENTAL METHODS

Host Plant

The host site for the pilot plant is Allegheny's Mitchell Station in Courtney, PA. The technology is being tested on a 16,500 lb/h (3640 scfm, equivalent to 1.7 MW) slipstream of the flue gases from the 288-megawatt, coal-fired Unit No. 3. Unit 3 entered service in 1963. It is corner-fired, and it is equipped with a Thiosorbic Lime wet flue gas desulfurization system and an electrostatic precipitator, but not with a selective catalytic reduction system. The station typically burns northern Appalachia bituminous coal. The range of values of some important characteristics of the coal burned during the pilot plant tests described here, follows: sulfur content, 3.0 – 4.8% dry basis; chlorine, 0.05 – 0.09% dry basis; ash content, 9.3 – 15% dry basis; mercury content, 0.09 – 0.13 mg/kg (ppm) as determined basis.

Pilot Plant and Test Program

Figure 2 shows the connections of the pilot plant to the host plant and the arrangement of the pilot plant equipment. The pilot air heater was sized to be sufficiently large for accurate performance evaluations. As a result, it is sized for a considerably higher gas throughput than the pilot ESP can handle. Therefore, as shown in Figure 2, the pilot plant splits off the excess flue gas between the two devices to maintain acceptable flow rates for both. For the tests described here, flue gas flow rates were about 14,000 lb/h at the air heater inlet and about 3,600 lb/h at the ESP inlet. The gas sampling locations are indicated in Figure 2 by the symbol \otimes . As operated for the tests described here (only two of three fields operating), the pilot ESP had a specific collection area of about 100 ft²/1000 acfm. Referring to Figure 2, the gas residence times between A and H is

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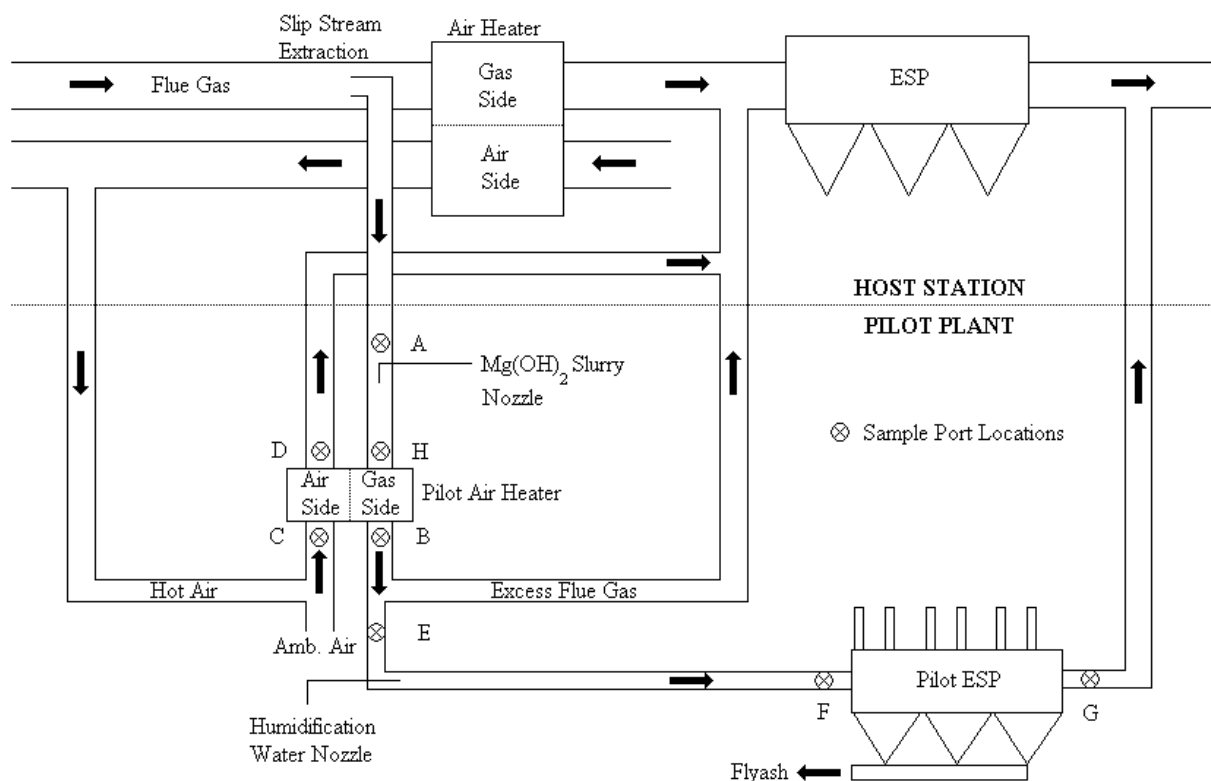
1.9 s; between H and B is 0.75 s; between B and E is 1.6 s; between E and F is 2.3 s; and between F and G is 7.3 s (assumes the temperature is constant except for a drop across the air heater is from 600 °F to 240 °F, and flow rates as described above). Gases were analyzed to determine Hg, particulate matter, sulfur dioxide (SO₂), and SO₃, and Hg was speciated into elemental, oxidized, and particulate Hg at the inlets and outlets of the air heater and ESP via the Ontario Hydro method (ASTM D-6784-02). All SO₃ sampling was conducted using the controlled condensation sampling method. Pilot plant ESP flyash was also sampled for mercury and carbon determinations. Occasional samples of the coal and ESP flyash from the host plant were also analyzed for a variety of properties.

The Mg(OH)₂ used in the pilot plant tests is a by-product slurry from the Thiosorbic Lime scrubber at the Allegheny Energy Pleasants Station in Willow Island, WV. The slurry was transported to Mitchell Station as a concentrate; it was diluted with water prior to injection into the 20" duct to facilitate atomization through the air/slurry nozzle.

The test program includes short-term parametric tests and long-term operation testing. The short-term parametric tests, which are complete, were operated at the following conditions:

- Baseline tests: 290-315 °F flue gas temperature at ESP inlet, no magnesium hydroxide injection; similar to the host plant conditions
- Flue gas cooling tests: deep cooling of the flue gas via the air heater or water spray to 220-240 °F at ESP inlet, and injection of magnesium hydroxide at a molar ratio of 2/1 to 5/1
- Maximum flue gas flowrate: 16,500 lb/h (3640 scfm), equivalent to the flue gas from 1.7 MWe of capacity. All tests described here were operated near 14,000 lb/h at the air heater inlet and 3,600 lb/h at the ESP inlet.

The test program includes a series of long-term tests to evaluate the impact of the technology on the performance of the air heater and ESP, corrosion of plant components, and stability toward leaching and volatilization of the Hg collected with the flyash.

Figure 2. Process Schematic of CONSOL/Allegheny Mercury Control Pilot Plant

RESULTS AND DISCUSSION

Sulfur Trioxide Control

A diluted $\text{Mg}(\text{OH})_2$ slurry was injected into the flue gas slipstream before the air heater to control sulfur trioxide (SO_3) concentration to prevent acid condensation. Injection was performed with an air/slurry nozzle mounted in a 20" diameter duct. Flue gas temperatures at the air heater inlet varied between 590-620 °F during the test periods described here. Table 1 shows SO_3 concentrations (and the acid dew points) at various locations in the pilot plant during test periods with no injection of magnesium hydroxide and during periods in which the magnesium hydroxide was injected at Mg/SO_3 molar ratios of 1.9/1 and 4.0/1. The SO_3 concentration at Location A (inlet) during the period with no magnesium hydroxide injection (baseline condition) is lower than that at the same location during the periods with magnesium hydroxide injection as a result of host plant operations. The higher SO_3 concentrations appear to be more typical. The targeted SO_3 concentration of 2 ppmv or less at the air heater inlet was achieved with a 4.0/1 Mg/SO_3 molar ratio. Therefore, all later testing was conducted with magnesium hydroxide injection at a Mg/SO_3 molar ratio at or near 4/1.

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Table 1. Effectiveness of Mg(OH)₂ Injection for SO₃ Control

Mg:SO ₃ Mole Ratio	SO ₃ Concentration, ppmv (Acid Dew Point, °F)		
	Before Mg Injection (Location A)	After Mg Injection, Air Heater Inlet	Air Heater Exhaust (Location B)
None (Baseline)	12.5 (274)	-	2.1 (237)
1.9/1	31.4 (278)	6.8 (256)	1.2 (230)
4.0/1	32.5 (288)	1.8 (236)	0.7 (222)

Mercury Capture

Mercury capture by the electrostatic precipitator (ESP) was measured at four different test conditions:

1. Baseline conditions: no magnesium hydroxide injection; flue gas cooled with the air heater to 320 °F at air heater exit and 290 °F at ESP inlet
2. Intermediate air heater cooling conditions: magnesium hydroxide injection, flue gas cooled with the air heater to 250 °F at air heater exit and 235 °F at ESP inlet
3. Deep air heater cooling conditions: magnesium hydroxide injection, flue gas cooled with the air heater to 234 °F at air heater exit and 220 °F at ESP inlet
4. Intermediate water spray cooling conditions: magnesium hydroxide injection, flue gas cooled with the air heater to 312 °F at air heater exit, then with water spray to 240 °F at ESP inlet

A diluted Mg(OH)₂ slurry was injected into the flue gas slipstream before the air heater whenever flue gas temperatures were lowered for test conditions 2-4. Mercury sampling was performed with the Ontario-Hydro Mercury Speciation Method (ASTM Method D-6784-02). All sample runs were 120 minutes in duration, with sampling occurring simultaneously at each location. Three sampling runs were done at each test condition. Mercury mass balances were calculated around the ESP to verify the reliability of the sampling data. Only those data from periods with mercury material balances of 100% ± 20% were accepted. The mercury capture by the ESP is shown in Table 2.

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Table 2. Mercury Capture by ESP

Test Condition	Mg:SO ₃ Mole Ratio	Temp., °F AH Exhaust (Location B)	Temp., °F ESP Inlet (Location F)	Hg Capture By ESP, mass % (each sampling run)	Hg Capture by ESP, mass % avg. ± std. dev. (best values)	“Carbon Treat Rate” lb C per million acf
Baseline	0/1	320	290	9*/14/39	26 ± 18	26
Mg(OH) ₂ AH Cooling	1.9/1	250	235	40/31/29	34 ± 6	27
Mg(OH) ₂ AH Cooling	3.5/1	234	220	48/35/83*	42 ± 9	18
Mg(OH) ₂ WS Cooling	3.4/1	312	240	17*/48/50	49 ± 1	23

**Indicates poor or no Hg mass balance for sample; they do not appear in average*

As shown in Table 2, mercury capture at baseline conditions is about 26%. As the ESP inlet temperature is lowered with the air heater to 220 °F at the ESP inlet (and with magnesium hydroxide injection), the mercury capture increases to about 42%. With water spray cooling to 240 °F at the ESP inlet and with magnesium hydroxide injection, the mercury capture is about 49%. The unburned carbon in the flyash and the gas flow rate were used to calculate the “carbon treat rate”, in a manner similar to that reported for mercury capture tests with powdered activated carbon injection. In this case, however, the carbon is simply the unburned carbon on the flyash that is native to the flue gas. The “carbon treat rate” is also shown in Table 2. It is possible that the lower apparent mercury capture obtained in the deep air heater cooling period relative to that obtained with intermediate water spray cooling, may result from the low “carbon treat rate” during that period.

Figure 3 shows a time plot of the mercury concentration in the flyash taken from the pilot ESP at the four different pilot plant conditions and from the host station ESP. The 2004 pilot plant data include only those periods with acceptable mercury mass balances. Mercury material balances were not completed when the 2003 baseline data were taken. Those early pilot plant data are included to show that, at baseline conditions, the pilot plant flyash has the same mercury concentration as the host plant flyash. However, the pilot plant flyash collected during periods in which the temperature was reduced and magnesium hydroxide was injected contains increased amounts of mercury illustrating the capture of mercury by the flyash at operating conditions.

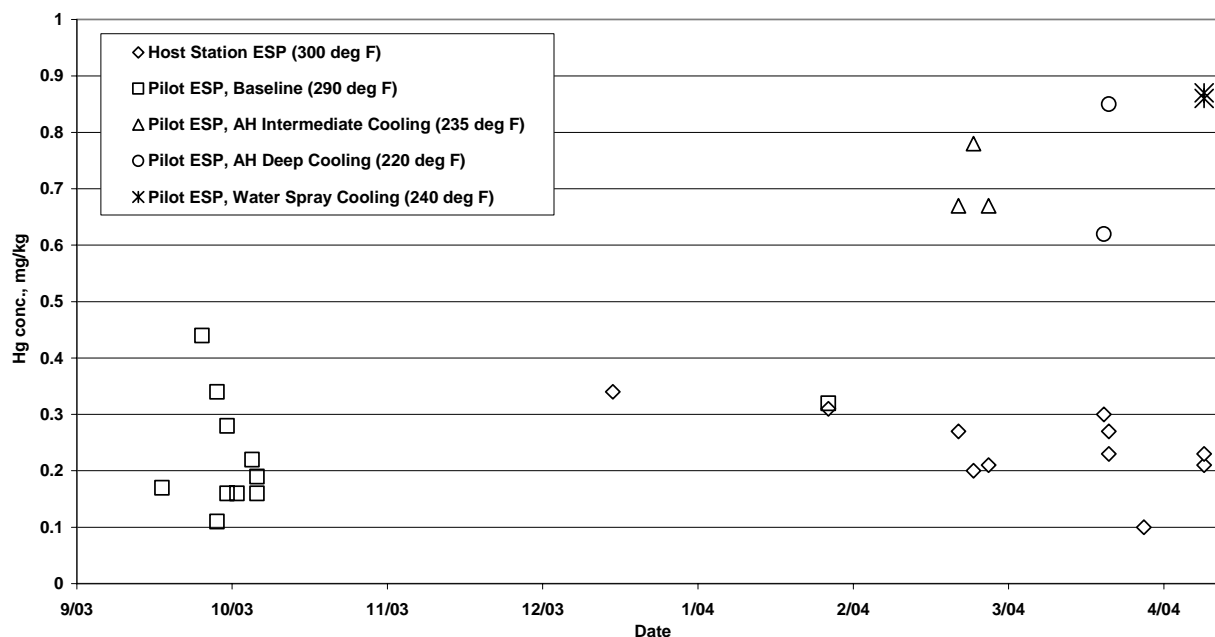
Figure 3. Mercury in ESP Flyash

Figure 4 shows mercury concentration as a function of unburned carbon content in the flyash taken from the pilot ESP at the four different pilot plant conditions and from the host station ESP. The pilot plant data include only those periods with acceptable mercury mass balances. As also shown in Figure 3, Figure 4 shows that the pilot plant flyash contains increased amounts of mercury as the flue gas temperature was lowered; however, Figure 4 may also indicate that mercury content in the flyash, and thus mercury capture, increases as the carbon content of the flyash increases. Evidence for this is the reasonably good correlation between the mercury concentration in the pilot ESP flyash and the carbon content in the same material, when limiting the data set to only those data generated with flue gas cooling to <250 °F at the ESP inlet (in other words, when omitting the baseline data). The linear regression is shown in Figure 4. Durham^v also reported that mercury capture on native flyash improves with increasing loss on ignition (LOI, a surrogate for carbon content) and with decreasing flue gas temperature, although the range of LOI contents and the range of temperatures examined were both higher than those examined in this work.

Table 3 shows the mercury speciation results obtained from the Ontario Hydro sampling method for flue gas sampled at the pilot ESP inlet and the pilot ESP outlet at the baseline conditions. The data suggest that, at the baseline condition, there may be a small apparent conversion of particulate mercury to elemental and ionic mercury as the flue gas traverses the ESP.

Table 4 shows the mercury speciation results obtained from the Ontario-Hydro sampling method for flue gas sampled at the pilot ESP inlet and the pilot ESP outlet at the deep air heater cooling condition. At these conditions, the data taken at face value suggest that there is a great apparent conversion of particulate mercury to elemental and ionic

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mercury as the flue gas traverses the ESP. This result is highly suspect. Our interpretation is that, at the high-dust-loading and cool

Figure 4. Mercury vs. Carbon in ESP Flyash

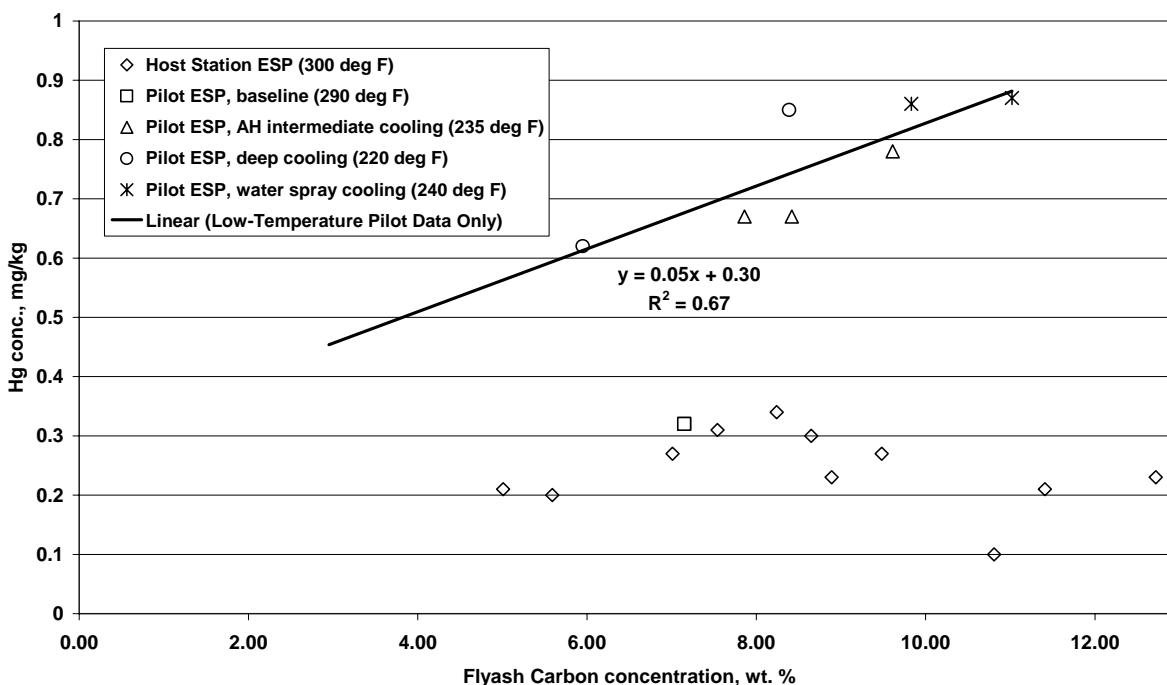


Table 3. Mercury Speciation via Ontario Hydro Method at Baseline Conditions – No Mg(OH)₂, 290 °F (1/29/04)

	Mass Flow Rates, µg/s		% Change
	ESP Inlet Location F	ESP Outlet Location G	
Hg ⁰	0.55	0.70	27
Hg ⁺⁺	2.2	2.7	19
Hg ^{part}	1.1	0.0	-100
Hg ^{tot}	3.9	3.4	-13
Hg in ESP Flyash	-	0.99	NA
Sum	3.9	4.4	12

conditions at the ESP inlet, some of the elemental and ionic mercury in the flue gas condenses on the particulate matter on the filter at the tip of the sampling probe. Thus, these results strongly suggest that the Ontario-Hydro Mercury Speciation Method may not be valid for conditions with high dust loading and temperatures of 250 °F and below. This would not invalidate the total mercury result, only the speciation results. The ESP outlet gas contains virtually no particulate matter and, therefore, it is expected that those speciation results are meaningful.

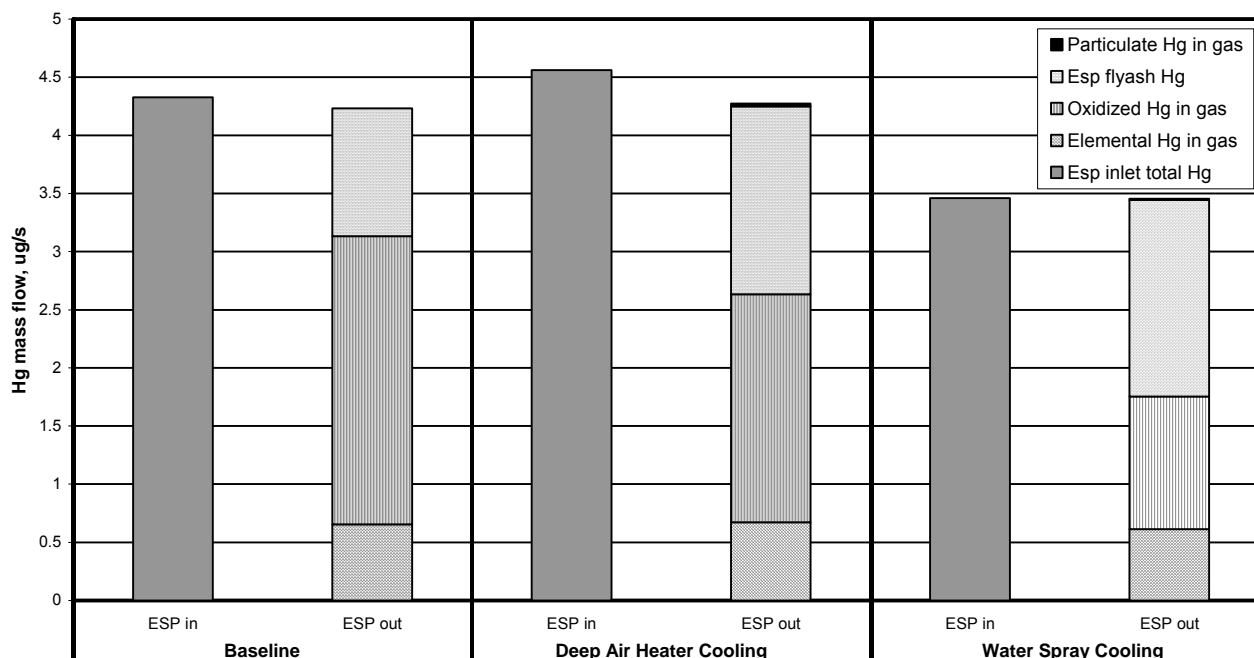
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Table 4. Problems with Mercury Speciation via Ontario Hydro Method at Deep Cooling Conditions – 3.5/1 Mg(OH)₂, AH to 220 °F (3/24/04)

	Mass Flow Rates, µg/s		% Change
	ESP Inlet Location F	ESP Outlet Location G	
Hg ⁰	0.16	0.74	363
Hg ⁺⁺	0.68	1.6	131
Hg ^{part}	3.6	0.02	-99
Hg ^{tot}	4.5	2.3	-48
Hg in ESP Flyash	-	1.5	NA
Sum	4.5	3.8	-15

Figure 5 shows mercury mass flow rates at the pilot ESP inlet and at the pilot ESP outlet during tests at the baseline, deep air heater cooling, and intermediate water spray cooling conditions. Only the total mercury concentration is shown for the ESP inlet because of the speciation problems described above.

Figure 5. Mercury Speciation at ESP Outlet



Mercury speciation results are shown at the ESP outlet. At the ESP outlet, the mass flow rate of mercury contained in the flyash captured by the ESP is shown. The similar sizes of the two bars at a given condition reflect the good mercury material balances. The greater mercury capture by the ESP (and greater removal from the flue gas) at the deep and intermediate cooling test conditions relative to the baseline conditions is

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evident. However, the mass flow rate of elemental mercury remained nearly the same for all three conditions. This appears to indicate that intermediate and deep cooling of the flue gas does not remove more elemental mercury than that obtained at baseline conditions; that the additional removal is primarily oxidized mercury.

Operating Experience

There has been no increase in pilot air heater pressure drop after 84 h operation with magnesium hydroxide slurry injection during the short-term tests described above. The pilot ESP has performed satisfactorily at operating conditions (with magnesium hydroxide injection at reduced temperature) during these short-term tests.

CONCLUSIONS

The following principal conclusions can be drawn at this stage of the test program:

- $\text{Mg}(\text{OH})_2$ slurry injection between the economizer and air heater is effective for removal of sulfur trioxide.
- Mercury removal with the ESP is improved with decreased ESP inlet temperature and may be improved at the lower temperatures with higher unburned carbon content in the flyash.
- Approximately 50% ESP mercury removal was demonstrated with cooling via air heater or water spray. At baseline conditions, mercury removal was about 25%.
- Emissions of elemental mercury were about the same at low-temperature conditions and at baseline conditions. Thus, the additional mercury removed at lower temperatures is mostly oxidized mercury.
- The Ontario-Hydro mercury speciation method appears to suffer problems with high-dust streams at temperatures of less than or equal to 250 °F.

The test program will continue for another four months and will include long-term testing, evaluations of air heater and ESP performance and corrosion, and an evaluation of the stability of the mercury captured by the flyash. Long-term tests are planned for conditions in which the air heater is used to cool the gas to about 225 °F at the ESP inlet, and for conditions in which the water spray is used to cool the gas to as close to 225 °F as operations permit. In both cases, magnesium hydroxide injection will be used. Final reporting will be completed in March of 2005.

Whatever final form mercury emission reduction regulations take, it is likely that a suite of technologies, each suited to different power plant situations (e.g., size, location, age, available space, etc.) will be required to meet them. The results of this program to date, which are based on the short-term tests, indicate that this technology concept may be a viable method of reducing mercury emissions from coal-fired power plants, particularly should a cap and trade regulatory approach be chosen.

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